COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Distributed Generation NOI	)	D.T.E. 02-38

INITIAL COMMENTS OF THE
SOLAR ENERGY BUSINESS ASSOCIAITON OF NEW ENGLAND

Introduction

The Solar Energy Business Association of New England ("SEBANE") is pleased to present the following comments in response to the Request for Comments issued by the Department of Telecommunications and Energy ("Department" or "DTE") as part of its Notice of Inquiry into distributed generation. Distributed Generation NOI, D.T.E. 01-38 (June 13, 2002).

SEBANE is a business association of solar energy companies. SEBANE's member companies include some of the world's leading photovoltaic ("PV") manufacturers, as well as PV system designers, developers, and installers. SEBANE members are all based or do business in New England. They sell products and services here and in the national and international marketplace. One of SEBANE's major initiatives is a regulatory barriers project, which is focused on reducing regulatory barriers to the development of PV and other small and behind the meter generation. The project is funded through a grant from the Massachusetts Technology Collaborative.

SEBANE's comments reflect the perspective of the solar electric generation industry, particularly solar photovoltaic power. Solar electric systems are most commonly deployed as distributed generation ("DG"). However, there are also many other types of DG that have very different characteristics, and have different effects on the environment and system reliability. For this reason, it is important to recognize that all DG is not equal and some regulations that apply to all types of DG might better be modified to differentiate the characteristics, benefits and costs associated with particular types of DG.

There are several benefits from encouraging DG of all types as a general utility policy. First, DG brings generation closer to end users, and therefore reduces the cost of transmission and distribution of electricity and reduces the vulnerability of the electric system. Second, DG enables customers to use strategies to control their energy costs better, meet a range of other energy needs, or satisfy a desire for improved environmental performance for themselves that benefits all ratepayers as well. There are benefits of DG for individual ratepayers such as improved on-site reliability, emergency power, the ability to transform energy waste streams into useful purposes, as well as environmental benefits of some DG. Utility policy should encourage private investment in generation that will have overall societal benefits (environmental in some cases, reduced need for the societal costs of new "central station" generation, etc.).

The fact that there is a wide range of DG, from diesel generators to PV to combined heat and power cogeneration facilities, also means that it is worth incorporating modifications to any broad set of rules based on the characteristics of the particular generation type. For this reason, SEBANE believes that some characteristics of PV, such as very predictable patterns of generation (enhanced summer production, daytime generation when most customer load facilities are in full use, use of inverter technology for power quality and safe, clean and quiet generation) justify rule modifications based on these characteristics.

There may be cases where modifications to an overall DG set of policies are appropriate for other types of generation, but SEBANE will focus only on solar electric generation in these comments.

I. Interconnection standards and procedures

Historically utility standards and procedures have been barriers to DG as a result of two types of utility requirements. First is the traditional high level of utility industry specific engineering and analysis originally needed for large, central-station generation facilities, but now associated with the protection and relaying of all generation connected to the grid, either directly or indirectly from behind the customer's meter. Second, are the rates that were designed to discourage generation that was competitive with utility-owned generation or to protect utility revenues. Since, early standards for non-utility generation were focused mostly on large-scale generation envisioned under PURPA in the late 1970s, the application of these rules to small or behind-the-meter DG systems was burdensome and often discouraged investment in these technologies.

Significant progress has been made in recognizing the benefits of small DG and in recognizing the real engineering issues associated with small generation systems. The Electric Restructuring Act and recent rules for system interconnection adopted by Massachusetts Electric Company ("MECo") (M.D.T.E. No. 1052) have significantly reduced the interconnection and rate barriers to small generation. Most importantly, the

Massachusetts Electric interconnection rules codified, clarified and simplified their procedures for DG systems (such as PV) that utilize inverters rather than rotating machines (induction or synchronous generators) to interconnect with the distribution utility.

While many improvements have been made, some additional improvements should be made and uniform standards and procedures should be adopted across the state.

The Department should use the Massachusetts Electric Interconnection Standard as the Basis for a Statewide Standard

Although there have been statewide standards established in other states and NARUC has recommended a set uniform interconnection standards, in many cases these standards have not fully eliminated the arbitrary and discriminatory application of requirements in specific utility territories.

SEBANE recommends that the DTE use the new MECo standards noted above as a basis for a uniform Massachusetts interconnection standard. These should be reviewed to determine consistency with proposed NARUC national standards. However, based on preliminary analysis by SEBANE, there are areas where the MECo standards are in fact, complimentary to the NARUC standards, providing needed technical detail and administrative process.

There are some improvements to the MECo standards that we would recommend for solar electric generation. The recommended improvements are organized by the type of distribution system to which the DG is interconnected (radial or network), and by the degree of the process (Expedited Acceptance, Impact Study, and Detailed Study) needed to establish an interconnection agreement.

Protecting the safety of consumers, distribution company line crews, and the electric distribution system is an important component of any interconnection standards and SEBANE does not suggest that safety should be compromised to expedite renewable energy development. Rather, by following national standards, and using independent laboratory test results, it is possible to broaden the scope of the existing MECo standards without compromising consumer and utility safety. Following are suggested improvements to the interconnect standards that will help enable DG development and remove technical barriers.

Modify the Requirements for DG on Networked Distribution Systems:

SEBANE is encouraged that MECo has taken landmark steps to explicitly allow DG smaller than a defined power to interconnect with Networked Distribution Systems without reverse power relays and to permit larger DG with such relays. However, SEBANE submits that in the case of networked distribution systems, the MECo requirement that the DG be less than 1/15th of the minimum facility load to be relieved of the reverse power flow relay may be excessive for solar electric power systems. We propose that, for PV system, the threshold for requiring a reverse power flow relay be set at 1/15th of the minimum daytime (9 am to 5 pm civil time) demand. (In the following section we recommend a process to determine the minimum load for customers that do not have records of interval demand data.[1]) Experience with this standard may result in justifiable modifications (up or down) to this threshold.

[1] We would recast the requirement as a probabilistic determination that the load will be greater than the site generation with 99.999% (or some similar high 9's number) so as not to trip a network protector. SEBANE proposes an investigation into the means to reset Network Protectors when tripped because of solar

Increase the allowable size for solar generators connected to radial distribution systems:

SEBANE suggests that for sites served by radial distribution, the capacity limit for solar electric generation be set at 75% of the distribution transformer capacity serving the customer.

Implement a process to expedite approvals for generators with UL and IEEE compliance:

The second way to reduce barriers is to have uniform procedures for establishing an interconnection agreement. The MECo regulations define two levels of studies (Distribution Facilities Impact Study and Distribution Facilities Detailed Study) and provide an exemption from these studies for systems under 10 kW. We would prefer that a third process, namely an "Expedited Acceptance" process, apply in the following situations:

- For customers served with radial distribution, if the solar electric generator capacity is less than 75% of the transformer capacity serving the customer, the inverter is in compliance with UL 1741, and the system complies with IEEE Standard 929-2000. Under this situation, the information submitted to the utility in the applicant's Notice of Intent to Interconnect will be verified by the utility and, if in accordance with the above requirements, a standard interconnection agreement will be offered to the applicant.

- For customers served with network distribution, the utility will conduct a 30-day load survey to determine the minimum demand on the network interface protection device connecting the customer to the network distribution system. The maximum allowable distributed generation on the secondary of the network protector will be 1/15th of this minimum connected daytime load. Under this situation, the information submitted to the utility in the applicant's Notice of Intent to Interconnect will be verified by the utility and if in accordance with the

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generation. Since solar time of day bounds for generation can be determined, PV specific determinations will require statistical analysis of solar power generation and building load profiles.

above requirements a standard interconnection agreement will be offered to the applicant.

- In both cases noted above the applicant will receive Expedited Acceptance regardless of the size of the solar generator up to 300 kilowatts.

National Standards

Massachusetts Electric Company has cited the proper national standards in its interconnection tariff.

The IEEE is in the process of writing a comprehensive interconnection standard, IEEE 1547, which will cover all types of distributed generation in addition to photovoltaic power. Although it is still in its draft stage, it is possible for Massachusetts to adopt IEEE 1547 in its draft form. This is a normal practice for local and state governing bodies when a standard reaches a final draft stage. SEBANE recommends that the DTE become familiar with this draft standard and anticipate its imminent availability.

Once DTE adopts this approach, it should impose a short transition period, six months or less, for all regulated utilities in Massachusetts to comply.

II. Standby Service Tariffs

The appropriate method for calculating standby and related charges should include an exemption for distributed generation from renewable energy sources.[2] There is significant precedent and a policy basis for this position, including the following regulatory and statutory provisions:

[2] SEBANE proposes using the definition of renewable energy generating sources from the Massachusetts Renewable Portfolio Standard. M.G.L. c. 25A, §11F.

220 CMR 11.04 (7)(c) -- The Department's regulations provide an explicit prohibition on standby-type charges for net metering customers:

> Distribution companies are prohibited from imposing special fees on net metering customers, such as backup charges and demand charges, or additional controls, or liability insurance, as long as the generation facility meets Interconnection Standards and all relevant safety and power quality standards.

D.T.E. 99-47 – One of the provisions of the settlement agreement for the NEES/EUA merger,[3] which was approved by the Department in a March 14, 2000 Order, established a basis for an exemption for renewable DG from a future MECo standby (Auxiliary Service) rate. The exemption was summarized as follows by the Department in that Order:[4]

> The Settlement exempts the following technologies from the Auxiliary Service Rate: non-dispatchable cogeneration facilities; heating and cooling systems at the customer's location; and non-dispatchable,[5] renewable energy facilities. (Settlement at 13).

M.G.L. Chapter 40J: Section 4E -- The 1997 Restructuring Act clearly establishes that there is a "public purpose[6] of generating the maximum economic and environmental benefits over time from renewable energy to the ratepayers of the commonwealth" and defines the following "public interests" in renewable energy:

> (i) the development and increased use and affordability of renewable energy resources in the commonwealth and the New England region; (ii) the protection of the environment and the health of the citizens of the commonwealth through the prevention, mitigation, and alleviation of the adverse pollution effects associated with certain electricity generation facilities; (iii) the delivery to all consumers of the commonwealth of as many benefits as possible created as a result of increased fuel and supply diversity; (iv) the creation of additional employment opportunities in the

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[3] New England Electric System and Eastern Utilities Associates Merger: Docket D.T.E. 99-47, submitted November 29, 1999 – Volume 1 of 2 – SETTLEMENT AGREEMENT, section 1.C. (1)(c) "New Onsite Generation" (page 11).
[4] Footnote 22.
[5] Solar photovoltaic generation is an example of a non-dispatchable facility.
[6] This public purpose is also stated in the Department's regulations at 220 CMR 11.04 (7)(a)(2).

> commonwealth through the development of renewable technologies; (v) the stimulation of increased public and private sector investment in, and competitive advantage for, renewable energy and related enterprises, institutions, and projects in the commonwealth and the New England region; and (vi) the stimulation of entrepreneurial activities in these and related enterprises, institutions, and projects.

M.G.L. Chap. 164 Section 1G (g) – The 1997 Restructuring Act also highlights the public interest in renewable energy by exempting it from exit fees in the following section:

> Effective as of March 1, 1998, if the utility and the department have received at least a six months notice of the customer's plans to install on-site cogeneration equipment, **renewable energy technologies**, fuel cells, or to purchase electricity through cogeneration equipment, a customer that reduces purchases of electricity through the operation of, or purchases from, on-site generation or cogeneration equipment, shall not be subject to an exit charge if …(ii) the customer reduces purchases through the operation of, or purchases from, **on site renewable energy technologies**, fuel cells, or cogeneration equipment with a combined heat and power system efficiency of at least 50 percent, based upon the higher heating value of the fuel used in the system; or (iii) the customer reduces purchases through the operation of, or purchases from, an on-site generation or cogeneration facility of 60 kilowatts or less which is eligible for net metering. (emphasis added)

Other states. Approximately 35 states have net metering of some sort for small renewables, and each of these states exempts small renewables from standby charges. In 2001, California enacted AB 29 which allows for all small renewables that are 1 MW or less to qualify for net metering and provides them with an exemption from any standby charges. In addition, there is no MW installation cap or threshold in each distribution company service territory that might trigger proceedings related to the development of standby charges.

We recommend that the Department affirm the public policy benefits of PV and other renewable generation and explicitly exempt such generation from standby and related charges that would otherwise significantly constrain distributed renewable development.

III. Role of distributed generation with respect to least-cost distribution service

Distributed generation can provide benefits to reduce the costs of operating the utility distribution grid in several ways:

- Defer or completely avoid the expenses of installing upgraded distribution equipment due to load growth.
- Defer or reduce the level of outages from stress on component parts of the system during peak use.
- Reduce system congestion at the distribution level where overloaded circuits cause difficulties in transportation of power throughout the grid.

There are numerous types of distributed generation that vary with respect to:

- Level of dispatchability or output profiles. Fuel cells may function more like a base load system, solar tracks summer peak in a relatively predictable pattern and standby generators may be dispatchable but temporary or voluntary.
- Environmental impact. Some sources can be clean and pollution free while others are more polluting than existing system power on the margin.
- DG system size and configuration as well as the level of combined system impact will have an impact on the ability of DG to actually achieve the benefits to the distribution grid.
- Ancillary benefits to the system or the ratepayer such as noise, ease of operation etc.

The issues of distribution system planning and the use of DG and/or energy efficiency to avoid or reduce system investments or lower costs extend beyond just solar as a resource option. For this reason, we are presenting a broad framework to address this issue that establishes equity between resource options, the principle of market response to opportunities, and a system to implement a strategy on a pilot basis to help increase the understanding of this opportunity prior to a larger level of utility or societal investment. We look forward to reaction to this framework and to participation in a dialogue with other stakeholders to identify strategies on how to move forward and better address this issue.

SEBANE Proposed Framework for Distribution Planning and Distributed Generation

In order for distributed generation and other on-site resources to play a role in distribution planning, distribution companies must:

- identify locations on the distribution grid where discretionary utility investments due to load growth or component replacement are needed;
- quantify the value of deferring or avoiding these investments; and
- establish a timetable for action.

Once these locations are identified and a calculation of costs established, then the value of avoiding those costs can also be established. This analysis can lead to implementing a strategy of using targeted incentives to reward placement of DG (and DSM) investments in locations where incremental distribution system savings can be achieved.

Distribution Companies should systematically perform the necessary planning to identify locations where impending load growth will require investments in system equipment (these studies may already exist). These should be projected out for a time period (3-5 years) where alternative strategies could be carried out. In addition, the load profile of projected load growth for that location should be identified so that appropriate on-site resources can be matched to the load profile, and to allow alternative investments to be planned accordingly. (For example, if the peak on a specific distribution sub-station was early evening then solar would clearly not be the appropriate resource).

The information about the avoided costs of reducing the load on a distribution point (station/sub-station/feeder etc.) combined with the necessary load profile, can be sent out to the market as a standard offer, called a Distribution System Standard Offer (DSSO). These standard offers would be set in $/kW increments and be capped based on projected desired load reductions (i.e. not to exceed a specific target load reduction to, e.g. avoid placing 100 MW of DG when only 10 MW was necessary). These standard offer price signals would represent some percentage of the incremental value of avoided distribution investments that would result from investments in DG or energy efficiency at those geographic locations. In this way, the savings produced by deploying on-site resources rather than distribution system upgrades would be shared by the ratepayers and the on-site resource developers. These standard offer price signals could vary by the avoided costs for each particular distribution location (or could be standardized if there is only small variation between locations).

Based on these standard offer pricing signals, the market for DG (or energy efficiency) would be able to respond and focus investment in those areas where the additional value from avoided distribution system costs is high, instead of areas where there is no added distribution system value. Any existing baseline incentives from public benefit funds, such as DSM programs and MTC programs, that are generally operated using average system benefits, could take note of the added locational benefits from the Distribution System Standard Offer to locate in a particular constrained area.

Example of How the DSSO would work

National Grid identifies that the Brockton area is in need of system upgrades in three years due to continued load growth. Over the planning horizon, the net present value of deferring this investment might be, say, $100 per kW. Based on these assumptions, a 50-kw solar installation might receive an additional $5,000 incentive ($100 per kW times 50 kW) for locating in the Brockton distribution area rather than some other non-constrained area in the National Grid territory. The same would be true of a landfill gas, wind or energy efficiency investment that reliably reduced loads. For projects with profiles that do not follow the desired load profile, then there may be some adjustment to the DSSO based on the degree of contribution.

Distribution Company Direct Ownership and Investment

Distribution companies should not be allowed to own or invest in distributed generation resources at this time. Using open market incentives, including payments for distribution system benefits, to encourage others to develop these resources is more consistent with the status of the energy markets and with both legislative and regulatory direction. Redirecting the distribution companies back into the power generation business would not be productive at this time.

Incentives for Distribution Company investments in DG to avoid system investments

Properly designed performance based rates (PBR) should provide the incentives for distribution utilities to invest in DG and energy efficiency where it is less expensive than distribution hardware. However, given the public policy benefits of expanding DG and efficiency, and the newness of using those tools as alternatives to distribution system upgrades, there may be a need to provide additional incentives through sharing of societal benefits and higher performance based rates for successful implementation of alternative distribution planning and investment strategies.

Cost, Complexity and Risk of Implementing Avoided Distribution System Investments

SEBANE recognizes that the process of identifying the avoided costs and corresponding load shapes for alternative investments in DG and DSM for distribution system planning is new and complex. We would suggest, however, that the exclusive focus by distribution companies on the cost of the wires justifies a very sophisticated planning approach. Further, we believe that the societal benefits of investing in these strategies strengthens the justification for taking the time and effort to carry out several targeted pilot efforts to prove the concept. We would suggest pilot studies conducted over three to five years, in multiple service territories, to establish Distribution System Standard Offers and evaluate market response to those offers.

There is a potential that planning will be carried out, avoided costs calculated, offers extended, and resources built that will defer less distribution system investment than expected or do so for a shorter than expected period of time. While there is the potential for the reverse, the upside and downside may not be symmetrical from a utility shareholder and societal perspective. For that reason, SEBANE proposes that these initial pilots be carried out with full cost recovery, but with no added incentives.

IV. Other issues: the Department should enhance the net metering rule.

The Department's net metering rule has helped to support the deployment of on-site, distributed generation. However, by adopting two, simple enhancements to that rule, the Department could greatly expand opportunities for on-site generation. SEBANE proposes that these enhancements be available to PV and other renewable generation.[7]

The Department's existing net metering rule is found at 220 CMR 11.04(7)(c). It provides as follows:

> Net Metering. A customer of a Distribution Company with an on-site Generation Facility of 60 kilowatts or less in size has the option to run the meter backward and may choose to receive a credit from the Distribution Company equal to the average monthly market price of generation per kilowatthour, as determined by the Department, in any month during which there was a positive net difference between kilowatthours generated and consumed. Such credit shall appear on the following month's bill. Distribution Companies shall be prohibited from imposing special fees on net metering customers, such as backup charges and demand charges, or additional controls, or liability insurance, as long as the Generation Facility meets the Interconnection Standards and all relevant safety and power quality standards. Net metering customers must still pay the minimum charge for Distribution Service (as shown in an appropriate rate schedule on file with the Department) and all other charges for each net kilowatthour delivered by the distribution company in each billing period.

First, for PV and other renewable energy systems, the rule should be expanded to allow **true** net metering. Currently, the rule allows **monthly** net metering. The customer is allowed to run his meter backward over the course of the month. At the end of the month, however, the customer is paid the wholesale market price for any net generation,

[7] SEBANE proposes that the Department use the definition of "renewable generation" that is used in connection with the Renewable Portfolio Standard. M.G.L. c. 25A, §11F.

or billed at the retail rate for any net consumption. The customer starts from scratch for the next month.

Under **true** net metering, the customer is allowed to carry forward any net generation into the next month. The meter does not re-set at the end of the month; instead, the customer is allowed to use this month's positive net generation to offset next month's consumption.

True net metering has several advantages. First, it is much simpler administratively. The utility no longer has to calculate the value of the net generation, and issue a check or a credit to the customer on a monthly basis. Instead, the customer's kilowatt-hour balance just carries forward to the next month. Given that the sums involved are typically quite small, the current process just adds costs without providing any value.

Also, true net metering enables the customer to realize the value of his generation. PV systems are most likely to be net generators during peak hours in the summer months, when the generation has the greatest value both in the wholesale market and for strained distribution systems. Under monthly net metering, customers are under-compensated for net generation because they receive only a monthly average, energy only price for that generation. The price does not reflect the on-peak nature of the generation and the resulting greater value, both from an energy and distribution system perspective. With true net metering, customers will receive greater value for those net kWh.

Further, true net metering protects against potential abuse by greatly over-sized systems – systems that are designed to sell power into the grid rather than just offset on-site use. Since true net metering only allows the customer to offset usage, and never results in a payment by the utility to the customer, customers have no incentive to over-size systems.

Most other leading states have gone beyond monthly net metering for PV systems, and adopted either true net metering or annual net metering.[8],[9] These states include Rhode Island,[10] New Hampshire,[11] Maine,[12] New York,[13] and California.[14] Massachusetts should join these states and adopt true net metering for renewable energy systems.

Second, the Department should expand the net metering rule for PV and other renewable energy systems from the current 60 kilowatt limit to 100 kilowatts or 50% of the facility's service entrance capacity, whichever is greater. The 60 kW cap is discouraging the development of larger, commercial-scale PV systems, which are typically more cost effective to build than smaller, residential-scale systems. There are strong policy benefits to encouraging the deployment of larger systems. First, they of course do more than small systems to increase the total amount of PV generation in Massachusetts, thus generating environmental and fuel diversity benefits. Second, since larger systems are generally less costly on a kW basis than small systems, fostering

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[8] Under annual net metering, net generation carries forward from month to month within a year, but then resets at the end of the year. In some annual net metering states, the customer receives a check for the energy value of any net generation at the end of the year. In other states, any net generation at the end of the year is granted to the utility.
[9] Under annual net metering, the anniversary date – the date as of which annual net generation is calculated – is very important. Since PV systems produce their maximum output in the summer, the anniversary date needs to be in the spring to enable the customer to use summer generation to offset winter usage. Sound approaches are to allow the customer to set his own anniversary date, or to pick a uniform date such as the first meter read date after May 1.
[10] Rhode Island Public Utilities Commission, Docket No. 2710 (1998).
[11] N.H. Rev. Stat. §§ 362A:1-a, and 362-A:9.
[12] Code Maine Regs, Chapter 313 (1998)
[13] New York Public Service Law §66-j
[14] Cal. Pub. Util. Code §2827.

deployment of larger systems can help to move PV towards cost competitiveness with fossil generation.

Conclusion

SEBANE respectfully requests that the Department adopt the foregoing recommendations.

Respectfully submitted,

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Date: August 1, 2002